Amendments to the Specification:

Please replace the title on page 1 with the following rewritten title:

--SUBSEA ~~RISER SEPARATOR~~ SEPARATION SYSTEM--

Please add the following new paragraph after the title:

--**Cross References to Related Applications**

This application is a continuation of U.S. Patent Application No. 10/138,020 filed in the United States Patent and Trademark Office on May 2, 2002.--

Please replace the first full paragraph under "Field of the Invention" on page 1 with the following rewritten paragraph:

--This invention relates to ~~the~~ offshore resource-recovery devices and processes. More specifically, the invention is concerned with improved oil and gas or other multi-phase fluid production from offshore subsea wells, especially from ultra-deep offshore wells.--

Please replace the second full paragraph under "Background of the Invention" on page 1 with the following rewritten paragraph:

--For shallow water depth locations, a well and fluid delivery system typically includes a riser ~~and~~ with the remainder of the fluid delivery system ~~that is~~ generally located on a rigid platform structure fixed to a seafloor

anchor or foundation. For deepwater offshore platforms locations, e.g., offshore platforms located in waters having a depth exceeding about 1,500 feet (or about 457 meters), this type of fixed tower structure is typically not cost effective, and other types of facilities may be used, e.g., subsea wellheads and delivery systems.--

Please replace the paragraph bridging pages 2 and 3 with the following rewritten paragraph:

--One embodiment of the inventive fluid delivery system comprises a vertical, low-pressure fluid separator and integral vapor riser assembly having a liquid outlet port connected to a pump assembly, <u>which</u> preferably <u>comprises a</u> hydraulically<u>-</u>driven <u>pump</u>. The pump assembly increases the pressure of the separated liquid allowing the delivery of pressurized liquid to other fluid handling facilities at the surface. The pump speed is simultaneously controlled to limit the range of vapor/liquid interface levels within the separator. The large variation in liquid interface levels within the vertical separator also allows the use of a subsea hydraulically-driven pump (typically having a relatively slow reaction time especially if hydraulically<u>-</u>driven from a surface source of pressurized fluid) even during periods of system upsets. Because of the system upset tolerance, the relatively open system design, and <u>the</u> simplicity of the operating controls, the present invention is expected to be reliable, safe, and cost effective. Moreover, the removal of most of the liquid-phase from the vapor riser allows a minimum operating or reservoir abandonment pressure, minimizing the backpressure on the subsea well.--

Please replace the second full paragraph under "Brief Description of the Drawings" on page 3 with the

following rewritten paragraph:

--Figure 2 shows a side view of an alternative subsea separator, riser, and pump with the separator directly connected to the subsea well.--

Please replace the paragraph bridging pages 3 and 4 with the following rewritten paragraph:

--The multi-phase fluid inlet line 12 is in fluid communication and is thus supplied by a subsea well (not shown in Figure 1) or a manifold connected to a plurality of subsea wells. The pressurized outlet line ~~14a~~ 14 from the pump assembly 9 is connected to a connector block 15 and fluidly connected to the interior tubing 17 of a two-concentric-piped riser assembly 8. However, some applications may use a separate vapor riser and pressurized liquid piping or riser system, e.g., see Figure 2.--

Please replace the first full paragraph on page 4 with the following rewritten paragraph:

--In the embodiment shown in Figure 1, the inlet port and line 12 typically supplies a multi-phase mixture of liquids (e.g., crude oil, water and/or gas condensates) and vapors (such as carbon dioxide, methane and other light hydrocarbon gases) from a spaced apart well to the tubular separator 6. The entry direction of the multi-phase mixture to the tubular separator 6 includes a tangential component, forcing the multi-phase fluid into a whirling or cyclonic motion constrained within the diameter of the tubular separator 6. The cyclonic motion tends to force heavier liquids or more dense fluids to the circumferential walls of the tubular separator 6 while

allowing gravity to drain the separated liquids near the walls towards the bottom or lower outlet line 11. As flowrates increase, the whirling speed within the tubular separator may also increase, tending to improve separation efficiency (as compared with a horizontal separator where increased flow rates tend to degrade separator efficiency).--

Please replace the first full paragraph on page 5 with the following rewritten paragraph:

--The separated liquid from the tubular separator 6 is withdrawn through the lower outlet line ~~11a~~ 11 and conducted to a pump assembly 9. The pressurized liquid from the pump assembly 9 is conducted through the pump discharge line 14 and a riser connector block 15 to an inner conduit 17 (shown cutaway and dotted within the outer conduit 18 of the generally concentric riser assembly 8). The separated vapor or less dense fluid from the tubular separator 6 rises through the connector block 15 to the annulus outside of the inner conduit 17 and within the concentric riser assembly 8. In alternative embodiments, the pressurized and separated liquid from the pump assembly 9 can be conducted to other devices besides the concentric riser strings 8, e.g., conducted to the surface using a separate dedicated (liquid) conduit or riser string, conducted to a liquid collector or manifold, conducted to an injection well, conducted to a water-oil separator or other processing facilities, or conducted to an oil export pipeline or other flowline.--

Please replace the paragraph bridging pages 5 and 6 with the following rewritten paragraph:

--The concentric riser strings 8 preferably comprise 30-50 foot (9.14-15.2 meter) sections of 12-16 inch (30.5-40.6 cm) nominal diameter N-80 pipe having a nominal wall thickness of 1- 1½ inches (2.54-3.81 cm) for the outer pipe string 18 and 30-50 foot (9.14-15.2 meter) sections of 6-10 inch (15.2-20.5 cm) nominal diameter N-80 pipe having a nominal wall thickness of ½ -1 inch (1.27-2.54 cm) for the inner conduit or pipe string 17. ~~Separate riser strings 8~~The concentric riser assembly 8 also typically comprises couplings, instrumentation and control cabling/hydraulic fluid tubing. A minimum internal diameter of the inner tubing string 17 is preferably at least about 4 inches (10.2 cm), more preferably at least about 6 inches (15.2 cm) to allow cable tools to be lowered through the concentric riser assembly 8 and tubular separator 6.--

Please replace the second full paragraph on page 6 with the following rewritten paragraph:

--In one embodiment, the tubular separator 6 is essentially a widened and generally open portion of one or more riser tubular sections. The tubular separator 6 typically has a nominal diameter of no more than about 3 feet (0.94 meter) for the embodiment shown. Although there is no theoretical limit on the nominal diameter of the tubular separator 6 or <u>the</u> vertical separator <u>6</u> shown in Figure 2 ~~in other embodiments~~, the nominal diameter of the tubular separator typically varies from about 24 inches to 36 inches (or about 61.0 to 91.4 centimeters). This allows the tubular separator 6 to be picked up, handled, and installed ~~mostly~~ using ~~handling~~ equipment ~~used~~ <u>adapted</u> for riser ~~sections~~ <u>handling</u>.--

Please replace the first full paragraph on page 7 with the following rewritten paragraph:

--The operation of pump assembly 9 is preferably controlled by the pressure of the separated liquid sensed in the lower outlet line ~~11a~~ 11 as an indicator of liquid interface level in the separator. In an alternative embodiment, the pressure at a second port (e.g., at the second or emergency outlet port ED) is also sensed, and the pressure difference is used to control the operation of pump assembly 9. The liquid pressure or pressure difference is an indication of the height of the separated liquid within tubular separator 6 or between ports. Because of the significant distance ODR between the lower liquid outlet level LLOL and upper fluid inlet level UFIL, the height of separated liquid within the vertical separator can vary widely, e.g., it can range from at or near the lower liquid level outlet to at or near the upper fluid inlet level. Preferably, the separator nominally functions with a liquid height midway between the multi-phase inlet level UFIL and the lower liquid outlet level LLOL, but can vary to as high as near the connector block 15 or as low as near a second or emergency liquid outlet ED, e.g., the fluid interface level can vary by about 40 feet or 60 feet (12.2 or 18.3 meters) or more.--

Please replace the first full paragraph on page 9 with the following rewritten paragraph:

--The process of using the fluid delivery system ~~2~~ of the invention for normal multiphase flowrates (e.g., separating vapor and liquid from a mixed flow inlet stream) involves controlling the pump speed as a function of the height/pressure of the separated liquid in the ~~vertical~~ tubular separator 6. If the liquid inflow rate from the well increases and the liquid interface level rises, the pump speed will be increased to reduce the liquid level in the separator. If the liquid interface level in the tubular separator 6

falls, the pump can be slowed or shut down to generally maintain the desired liquid interface level.--

Please replace the first full paragraph on page 10 with the following rewritten paragraph:

--An advantage of the inventive ~~separation~~ fluid delivery system is reliability. The preferred embodiment comprises hydraulic pumps to avoid potential problems with electric-driven submersible pumps, e.g., power cable insulation breakdown, shorting, cooling surface contamination, galvanic corrosion, and other reliability problems. The use of power fluid components located at the surface makes these components easily accessible for maintenance and repair. Avoiding the need for control valves by controlling the speed of the hydraulic pump assembly 9 avoids potential problems of stuck valves, loss of control valve signals, contamination blockage of the control valves, and other valve reliability problems. Using tubular sections for the riser and tubular separator assemblies reduces potential damage by improper handling and improper connection designs. The use of tubular sections also makes for ease of handling, since rig crews are familiar with this type of equipment. Placing the essentially vertical riser on top of the nominally vertical tubular separator allows direct maintenance and repair access to the separator using wire line tools or other reliable well maintenance and repair procedures and tools well known in the art.--

Please replace the paragraph bridging pages 10 and 11 with the following rewritten paragraph:

--Figure 2 shows a schematic side view of an alternative embodiment of the inventive subsea fluid delivery system 2 directly connected to a well tubular 4 extending from an offshore oil & gas well 3 penetrating an underground reservoir R. Although the inventive fluid delivery system 2 shown may be connected to other onshore or offshore wells in shallower water depths penetrating reservoirs at various pressures, the system is expected to be most applicable to deep offshore wells penetrating low pressure reservoirs R and located in deepwater locations, especially ultra-deep water locations. Low pressure reservoirs ~~is~~ are herein defined as having a static pressure of less than the head pressure of sea water at about the depth under sea level where the reservoir is located. Even if a reservoir is initially not classified as a low-pressure reservoir, commercial production may cause the reservoir pressures to decline over time so that the reservoir, especially when near commercial depletion, is classified as a low-pressure reservoir at a later time.--

Please replace the paragraph bridging pages 11 and 12 with the following rewritten paragraph:

--The offshore or subsea well 3 has one or more strings of tubular sections 4 that extend generally downward from at or near a mudline level ML through formation F to at least a reservoir R with the tubulars typically cemented in place. The offshore well 3 may produce a mixed phase fluid, e.g., a crude oil/condensate and natural gas mixture. The well tubular sections 4 are fluidly connected to an inlet port of vertical separator 6 having at least two outlets, an upper outlet connected to a riser assembly 8 and a lower outlet connected to a pump assembly 9. Because vapor removal is via a relatively open gas riser ~~8a~~ 8 and the liquid is removed by pump assembly 9, back-pressure on the well 3 can be reduced to

as little as a few psig or the back-pressure generated by a column of low pressure gas extending from near the mudline to the surface level SL. Although internal pressures in the vertical separator 6 can be as much as 5000 psig or more, they more typically range from about 50 psig to several thousand psig. For very low pressure or depleted reservoirs, vertical separator pressures may be no more than about 500 psig, sometimes no more than ~~or even~~ 200 psig.--

Please replace the second full paragraph on page 12 with the following rewritten paragraph:

--In contrast to the embodiment of the invention shown in Figure 1, the offshore well 3 in Figure 2 directly supplies mixed-phase fluid flow as input to the vertical separator 6 through an extended nozzle ~~12~~ 12R that protrudes into the vertical separator. In alternative embodiments, similar vertical separators, risers, and/or pumped fluid delivery systems may also be supplied by multi-phase flow pipelines, subsea solution mining wells, geothermal wells, and other subsea sources of a fluid mixture requiring some type of separation.--

Please replace the last full paragraph on page 12 with the following rewritten paragraph:

--The subsea well 3 typically comprises several types of well tubulars 4, e.g., a casing string, a liner string, and a production string. Some of the tubular sections can have nominal diameters of 30 inches (76.2 cm) or 36 inches (91.4 cm) or more, but a typical well tubular connected to the separator ~~6a~~ 6 has a nominal diameter typically less than about 13 inches (33.0 cm).--

Please replace the first full paragraph on page 13 with the following rewritten paragraph:

--A connector 5 is used to attach well tubular 4 to ~~a~~ vertical separator 6. The connector 5 not only provides a duct-like passageway for fluids, but at least also partially supports vertical separator 6. Although connector 5 is typically weldably connected to well tubular 4 and the vertical separator 6, ~~bolted~~ bolting, ~~threaded~~ threading, or other means for connecting the well tubular to the vertical separator may be used. Because of potentially severe bending and other loads on the connector 5, the connector typically has a wall thickness greater than the vertical separator 6, well tubulars 4, and/or the tubular riser sections 7 extending down from the ship or surface platform S.--

Please replace the second full paragraph on page 13 with the following paragraph:

--Both the tubular separator 6 shown in Figure 1 and the vertical separator 6 shown in Figure 2 can be distinguished from prior art horizontal separators. For example, the separators 6 include a two-phase fluid inlet (item 12 in Figure 1 and item 12R in Figure 2) imparting a flow direction typically having a radial component and a tangential component. The fluid inflow impinges on the internal walls of ~~vertical separator~~ separators 6, causing a generally swirling internal fluid flow around a nominally vertical centerline. Separation is typically accomplished, at least in part, by the swirling motion that tends to throw denser fluids (e.g., liquid droplets) outwardly. The swirling liquid or other denser fluids coalesce on the walls and then gravity-flow downwardly towards outlet line 11 while the less-dense swirling fluids (e.g., gases) "float" upward and inward to be withdrawn from an upper and more central outlet

connected to the vapor riser assembly ~~7~~ 8.--

Please replace the paragraph bridging pages 14 and 15 with the following rewritten paragraph:

--In one embodiment with limited flowrates and/or not requiring extremely low back-pressure operation, the vertical separator 6 in Figure 2 is similar to the tubular separator 6 in Figure 1 in that it is composed of one or more well or riser tubular sections having thick walls. Use of available tubular ~~section~~ sections is possible since the nominal horizontal dimension or diameter of the vertical separator in this embodiment is equal to or less than the nominal diameter of available large risers, drill pipe, and/or other well tubular sections and the wall thickness is sufficient to withstand the differences in external and internal pressures. This allows common tools and/or procedures to be used for the vertical separator 6 and other tubulars, thereby simplifying handling, installation, maintenance and repair. In other applications where even lower pressure and higher flowrates require larger, thicker-walled construction of a vertical separator 6, e.g., over 36 inches (91.4 cm), especially over 48 inches (121.9 cm) in nominal diameter with more than a two inch (5.08 cm) wall thickness, cylindrically-shaped and welded forging sections can be used instead of pipe or other well tubulars.--

Please replace the first full paragraph on page 15 with the following rewritten paragraph:

--Referring again to Figure 2, the ~~The~~ pump assembly 9 is connected to and supplied by the liquid (or more-dense-phase) fluid outlet 11 of vertical separator 6. ~~After the~~ The

pump typically increases the pressure of the liquid to about the external (or seawater) head pressure at the subsea location or <u>to</u> at least the head pressure of the pressurized liquid at that location. The discharge line 14 typically ranges from about 2 to 12 inches (5.08 to 30.5 cm) in diameter and may ~~use~~ <u>comprise</u> thinner wall tubing or piping than the fluid outlet line 11. The discharge line 14 transfers the separated and pressurized liquid to other fluid handling devices, e.g., liquid storage facilities on the surface ship S. The liquid outlet line 11, discharge line 14, and hydraulic pump assembly 9 are at least partially supported by a piled or cemented footing foundation C located at or near the sea floor or mudline ML.--

Please replace the last full paragraph on page 15 with the following rewritten paragraph:

--The riser assembly ~~7~~ <u>8</u> is connected to the vapor or less dense fluid outlet of the vertical separator 6. The riser assembly ~~7~~ <u>8</u> is at least partially supported by a buoyancy can 10, but may also be supported by ship S, a buoy, platform or other means for supporting the riser assembly.--

Please replace the first full paragraph on page 16 with the following rewritten paragraph:

--In one embodiment, riser assembly ~~7~~ <u>8</u> comprises nominal 30-50 foot (9.14-15.2 meter) sections of 10-14 inch (25.4-35.6 cm) nominal diameter N-80 pipe having a nominal wall thickness of ¾-1¼ inches (1.90-3.18 cm). Besides ~~the riser~~ <u>these tubular</u> sections ~~8~~, the riser assembly ~~7~~ <u>8</u> may be composed <u>of</u> couplings, instrumentation and control cabling/ hydraulic fluid tubing. Typically, a minimum internal

diameter of at least about 4 inches (10.2 cm), preferably at least about 6 inches (15.2 cm), is maintained to allow cable tools to be lowered through the riser assembly ~~7~~ 8 and vertical separator 6.--

Please replace the second full paragraph on page 16 with the following rewritten paragraph:

--The mixed fluid inlet ~~12~~ 12R of the vertical separator can include a removable protruding and offset nozzle, but may also include deflectors, baffles, and other devices to generate a swirling motion. Removability of the fluid inlet ~~12~~ 12R allows cable tool access to the directly-connected well 3, and adjustment and/or replacement of the fluid inlet/nozzle for different quality fluid mixtures.--

Please replace the paragraph bridging pages 16 and 17 with the following rewritten paragraph:

--Figure 2 shows a floating drill ship, barge, or other surface platform S fluidly connected to the buoyancy can 10 and the vertical separator 6 with a portion of the riser assembly ~~7~~ 8. In alternative embodiments, the riser assembly ~~7~~ 8 may be connected to a ship S that is horizontally offset from the over-well position shown. In other embodiments, the drill ship may be supplemented or replaced by a spar, tension leg platform, semi-submersible vessel, or other surface fluid handling facility. In still other embodiments, instead of the vapor outlet of the vertical separator 6 being directly connected to a riser assembly ~~7~~ 8, the riser assembly can include an emergency dump valve (e.g., similar to the second or emergency port and valve ED attached to the tubular separator 6 as shown in Figure ~~2~~ 1) connected to buoyed flare

stack, temporary storage tanks (e.g., bladders), a secondary vapor handling facility, or other fluid-handling devices.--